ERCB Energy Resources Conservation Board

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Draft *Directive 051*

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Wellbore Injection Requirements

The Energy Resources Conservation Board (ERCB/Board) has approved this directive on XXX.

[*original signed by*]

Dan McFadyen
Chair

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1 Introduction

1.1 Purpose of *This Directive*

The purpose of *Directive 051: Wellbore Injection Requirements* is to detail the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements of any well used for injection purposes. Injection refers to fluids being introduced into a wellbore for the purpose of disposal, in situ bitumen recovery, enhanced recovery, hydrocarbon storage, in situ coal conversion, and in situ combustion. The requirements of this directive are designed to ensure hydraulic isolation of stored, injected, or disposed fluids, and to protect groundwater and energy resources.

Who *Directive 051* Applies to

This directive applies to any person or entity that has applied for or holds any approval, licence, or permit or that is subject to an order or direction made under legislation or regulations enacted or administered by the ERCB. References to "licensee" in this directive include applicants, approval holders, licensees, operators, and permit holders as applicable in the circumstances.

Overview of the Regulatory Framework for Injection Wells

Injection cannot begin until scheme and wellbore approvals have been granted. Scheme approvals are covered under *Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project*, *Directive 065: Resources Applications for Oil and Gas Reservoirs*, and the *Coal Conservation Act*.

Other requirements that relate to injection wells are covered under the following:

- *Directive 056: Energy Development Applications and Schedules* for well licensing requirements
- *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry* for approval of surface facilities associated with Class Ib disposal wells
- Surface facilities for waste disposal wells that are on nonoilfield sites (e.g., petrochemical sites) fall under the jurisdiction of Alberta Environment and Sustainable Resource Development (ESRD). Associated reporting and monitoring programs for the surface facilities are subject to ESRD requirements.

The ERCB also recommends that licensees be aware of the *Canadian Standards Association Standard Z341: Storage of Hydrocarbons in Underground Formations* (*CSA Z341*) for wellbores used to inject hydrocarbons for the purpose of subsurface storage.

1.2 What's New in this Edition

This edition of *Directive 051* replaces and rescinds the March 1994 edition of *Directive 051: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements*. A licensee should read the entire directive to become familiar with all of the current requirements. Major changes are listed below.

- Section 1.3: Added reference to *Directive 019: Compliance Assurance*.
- Section 1.5: Added a description of the application and submission process.
  - Figure 1.5.1: Added a schematic of the application and submission process.
- Section 1.6: Clarified the process for deficient applications.
- Section 1.7: Added information for determining the base of groundwater protection (BGWP).
- Section 2: Added a requirement that injection wells must meet all wellbore integrity logging, operational monitoring, and reporting requirements in this directive within five years of its effective date.
- Section 3: Added a table summarizing the injection well classifications (see Table 1).
- Section 3, Table 1: Revised the fluid characteristics for Class Ia and Ib to correlate with land disposal restrictions. Both classes of wells now have the same fluid characteristics, but Class Ia wells will only receive nonoilfield wastes and Class Ib wells will receive oilfield wastes or mixtures of oilfield and nonoilfield wastes.
- Section 3, Table 1: Reclassified Class IV wells to permit only the injection of nonsaline water.
- Section 3, Table 1: Added new Class V for steam injection, including production wells where steam injection occurs even for a limited period.
- Section 4: Added a table to provide a summary of key wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements for all well classes.
- Section 5: Added common wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements for all well classes.
- Section 5: Added a packer requirement on Class IV wells. A packer is now required for all well classes except for Class V wells and previously approved injection wells.
- Section 5: Clarified that all logs must be submitted under Section 11.140(1) of the *Oil and Gas Conservation Regulations* (*OGCR*) to the ERCB's ICD – Data Compliance Services (WellLogInquiries@ercb.ca). Initial logs must also be included with the *Directive 051* submission.
  - Section 5.1: Added new and revised initial logging requirements.
- Sections 6 to 12: Added revised casing and cementing requirements, casing inspection logs, cement integrity and hydraulic isolation logs, and operational monitoring and reporting requirements for all well classes.
- Section 11: Added Class V injection well for steam injection.
- Section 11: Clarified that wellbore design, wellbore integrity logging, operational

monitoring, and reporting requirements for Other Class V wells will be determined by the ERCB on a case-by-case basis.

- Section 11.2.2: Clarified that alternate monitoring plans in lieu of hydraulic isolation and multifinger caliper logging must be approved by the ERCB before beginning steam injection for Class V wells. All monitoring equipment must be installed and operational before beginning steam injection into a drainage pattern.
- Section 12: Added information on wellbore design requirements for in situ coal conversion and in situ combustion wells.
- Section 13: Added information on applying for downhole separation and injection.
- Appendix 3: Added a revised Sample Injection Wellbore Completion Schematic.

In addition to the above additions and revisions to this directive, the following sections from the 1994 edition of *Directive 051* have been removed and addressed elsewhere:

- Section 2.5: Waste Reporting. Now addressed in *Directive 058*, *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities*, and *Directive 007: Volumetric and Infrastructure Requirements*.
- Section 7.4: Area of Review, Section 8: Operating Parameters (Wellhead Pressure), Appendix 3: Step-Rate Injectivity Tests, and Appendix 5: Maximum Allowable Wellhead Injection Pressures are now addressed in *Directive 023* and *Directive 065*.

1.3 ERCB Requirements and Compliance Assurance

The term "must" indicates a requirement, while terms such as "recommends," "expects," and "should" indicate a recommended practice.

Noncompliance with any risk-assessed requirement will result in the licensee receiving a response in accordance with the latest edition of *Directive 019*. A list of noncompliant events is on the ERCB website www.ercb.ca.

The ERCB encourages all licensees to be proactive by monitoring their compliance with ERCB requirements. If a licensee identifies a noncompliance, it should inform the ERCB Well Operations Section at WellOperations@ercb.ca of the noncompliance for consideration under the ERCB Voluntary Self-Disclosure policy set out in *Directive 019*.

For further details on compliance assurance, including *Directive 019*, refer to the ERCB website www.ercb.ca.

1.4 Continuous Improvement

The ERCB continuously improves the requirements within its regulatory framework. As part of this commitment, the ERCB gathers information on the efficiency and effectiveness of *Directive 051* requirements through application auditing and data retention activities, and through feedback from stakeholders to ensure that the requirements of *Directive 051* evolve to meet the needs of all stakeholders.

1.5 *Directive 051* Submission Requirements

To be determined. Please refer to Bulletin 2012-16.

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1.5.1 *Directive 051* Form

All relevant sections of the *Directive 051* form (Appendix 1) must be completed and submitted with the required attachments. The ERCB will consider to be incomplete any form that has been filled out incorrectly or that is missing any of the required attachments, and the associated application may be closed. Upon a review of the application, the ERCB may request hard copies of any original logs. A sample form and instructions to complete the form can be found in Appendix 1 and Appendix 2, respectively.

1.6 Incomplete *Directive 051* Information

The ERCB will no longer process any application in which the *Directive 051* information is substantially incomplete (e.g., missing hydraulic isolation or cement integrity logs).

1.7 Determining the Base of Groundwater Protection

BGWP elevations are available for all locations across Alberta using the ERCB's Base of Groundwater Protection Query Tool in the ERCB's DDS system. For more information on the query tool and how to use it, refer to the ERCB's website www.ercb.ca under Data & Publications : Digital Data Submission (DDS) : Base of Groundwater Protection.

For any additional information or questions about the query tool, contact the Customer Contact Centre by telephone at 403-297-8311 or 1-855-297-8311 (toll free) or by e-mail at infoservices@ercb.ca.

1.8 References and Definitions

Appendix 4 contains a list of all acts, regulations, directives, bulletins, and interim directives that an applicant should be aware of when applying for an injection well.

Appendix 5 contains definitions of the terms used in this directive.

2 Existing Injection Wells

Injection wells that were approved before the release of this version of *Directive 051* may be subject to additional requirements.

1) Injection wells that were approved before the release of this directive must meet the current wellbore integrity logging, operational monitoring, and reporting requirements within five years of the effective date of this directive.

2) Injection wells that are reclassified must meet the requirements of this directive.

3 Types of Injection Wells

Injection wells are classified based on the characteristics of the fluid being injected. Table 1 presents the fluid types and characteristics for injection wells requiring approval under this directive.

Table 1 Injection well classifications

Well class	Purpose	Fluid characteristics
Ia	For injection of nonoilfield wastes. The operation of the associated surface facilities are regulated by ESRD.	A representative sample of the waste fluid must have • a pH between 4.5 and 12.5; • a flash point greater than 60^0C; • a polychlorinated biphenyl (PCB) concentration of less than 2 milligrams per kilogram (mg/kg); • a nonhalogenated organic fraction of less than 10 per cent by mass (less than 100 000 mg/kg), unless it is – an untreatable sand or crude oil / water emulsion, or – an antifreeze or dehydration fluid that contains greater than 60 per cent water by mass;
Ib	For injection of oilfield wastes or a mixture of oilfield and nonoilfield wastes. The operation of the associated surface facilities are regulated by the ERCB.	In addition to meeting the above criteria, information on the types and sources of wastes intended for disposal must be disclosed in the application for the disposal scheme. The information must support that the quality of the wastes is appropriate for the intended disposal zone based on well bore design/conditions, containment/isolation within the intended disposal zone, and protection of nonsaline water sources. The ERCB will consider the information on a case-by-case basis while also considering other applicable provincial and federal acts and regulations, as well as information from other jurisdictions on deep-well disposal.
II	For injection of produced or saline water.	A representative sample of the produced or saline water must have • a pH between 4.5 and 12.5; • a flash point greater than 60^0C; • a PCB concentration of less than 2 mg/kg; • a nonhalogenated organic fraction of less than 10 per cent by mass (less than 100 000 mg/kg) Provided the above criteria are met, the following fluids can be injected through a Class II wellbore: • produced water associated with the recovery of hydrocarbons, including water from sour production operations as defined in *Directive 056*. • brine from salt caverns (washing only) or solution mining operations (washing only); • water-based pigging fluids from cleaning of a collection or injection line provided it does not contain additional chemicals; • brine reject or backwash from water softeners associated with enhanced recovery; • water from enhanced recovery schemes (can contain polymers or chemicals); • water containing only calcium chloride ($CaCl_2$) or potassium chloride (KCL) provided it does not contain any additional chemicals or additives. Fluids produced back to surface immediately after a well has undergone workover/stimulation will contain higher levels of additives and are therefore considered well workover fluids (a type of oilfield waste), not produced water.
IIIa	For injection of acid gas.	Acid gas includes • hydrogen sulfide, • carbon dioxide, or • any combination of hydrogen sulfide, carbon dioxide, and

Well class	Purpose	Fluid characteristics
		other gas impurities.
IIIb	For injection of hydrocarbons or other gases.	Hydrocarbons or other gases include (no H_2S) • solvent or other hydrocarbon products; and • nitrogen, oxygen, air, or other gases.
IV	For injection of nonsaline water.	Nonsaline water is defined as water containing less than 4000 milligrams per litre of total dissolved solids.
V	For injection of steam*.	Steam.

*This includes production wells where steam injection occurs even for a limited period.

3.1 List of Fluids Prohibited From Injection

The following waste streams are prohibited from injection:

- municipal or industrial sewage;
- collected surface runon/runoff waters that meet surface discharge criteria (refer to *Directive 055: Storage Requirements for the Upstream Petroleum Industry*) or that can be treated cost effectively to meet surface discharge criteria, unless a *Water Act* licence is obtained from ESRD;
- lube oils or spent solvents;
- hydrocarbon-based drilling products and wastes; and
- wastes for which there is economically and technically appropriate treatment technology.

Hydrocarbon-based drilling wastes can be injected into waste caverns.

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4 Summary of Key Requirements

The key requirements of this directive are listed in Table 2. A licensee is expected to read, understand, and comply with all of the requirements for each well class.

Many requirements in *Directive 051* require that a licensee run hydraulic isolation, casing, and cement integrity logs. A summary of recommended logging practices is included in Appendix 6.

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Table 2 Key requirements

Class	Description	Wellbore design		Wellbore integrity logging		Operational monitoring and reporting
		Surface casing to	Casing and cementing	Hydraulic isolation and cement integrity	Casing integrity	
Ia and Ib						
	Oilfield and nonoilfield wastes	BGWP	Surface casing • cemented in accordance with *Directive 009: Casing Cementing Minimum Requirements.* Next casing string • cemented to surface.	Initial full-length cement integrity log and one of the following hydraulic isolation logs: • temperature • oxygen activation • radioactive tracer Hydraulic isolation logging every five years.	Initial full-length casing inspection log. Casing inspection log every 10 years.	• Continuous monitoring and recording of annular and tubing pressures • Conduct an annual packer isolation test for 10 minutes at the greater of 7000 kilopascal (kPa) at surface or 1.3 times the approved maximum wellhead pressure and report this information in accordance with *ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements 3) Casing Failure Reporting and Repair Requirements.*
II						
Case 1	Produced or saline water	Depth in accordance with *Directive 008: Surface Casing Depth Requirements.*	Surface casing • cemented in accordance with *Directive 009.* Next casing string • cemented to surface.	Initial full-length cement integrity log and one of the following hydraulic isolation logs: • temperature • oxygen activation • radioactive tracer	Initial full-length casing inspection log if the well is more than five years old.	• Monthly monitoring of annular and tubing pressures • Conduct and report annual packer isolation test in accordance with *ID 2003-01.* Any additional monitoring as determined by the ERCB
Case 2		Depth in accordance with *Directive 008*	Surface casing • cemented in accordance with *Directive 009.* Next casing string • cement top in accordance with *Directive 009.*			• Daily monitoring of annular and tubing pressures • Conduct annual packer isolation test in accordance with *ID 2003-01.* Any additional monitoring as determined by the ERCB
IIIa						
	Acid gas	BGWP	Surface casing • cemented in accordance with *Directive 009.* Next casing string • cemented to surface.	Initial full-length cement integrity log and one of the following hydraulic isolation logs: • radioactive tracer • cased hole neutron	Initial full-length casing inspection log. Casing inspection log every 10 years.	• Continuous monitoring and recording of annular and tubing pressures • Conduct an annual packer isolation test for 10 minutes at the greater of 7000 kPa at surface or 1.3 times the approved maximum wellhead pressure and report this information in accordance with *ID 2003-01.*

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Class	Description	Wellbore design		Wellbore integrity logging		Operational monitoring and reporting
		Surface casing to	Casing and cementing	Hydraulic isolation and cement integrity	Casing integrity	
				• oxygen activation • any approved log capable of detecting gas movement Hydraulic isolation log every five years.		
IIIb						
Case 1	Hydrocarbons or other gases.	Depth in accordance with *Directive 008*	Surface casing • cemented in accordance with *Directive 009*. Next casing string • cemented to surface.	Initial full-length cement integrity log and one of the following hydraulic isolation logs: • radioactive tracer • cased hole neutron log capable of detecting gas movement.	Initial full-length casing inspection log if the well is more than five years old.	• Monthly monitoring of annular and tubing pressures • Conduct and report annual packer isolation test in accordance with *ID 2003-01*.
Case 2		Depth in accordance with *Directive 008*	Surface casing • cemented in accordance with *Directive 009*. Next casing string • cement top in accordance with *Directive 009*.			• Daily monitoring of annular and tubing pressures • Conduct and report annual packer isolation test in accordance with *ID 2003-01*.
IV						
Case 1	Nonsaline water	Depth in accordance with *Directive 008*	Surface casing • cemented in accordance with *Directive 009*. Next casing string • cemented to surface.	Initial full-length cement integrity log and one of the following hydraulic isolation logs: • temperature • oxygen activation radioactive tracer	Initial full-length casing inspection log if the well is more than five years old.	• Monthly monitoring of annular and tubing pressures • Conduct and report annual packer isolation test in accordance with *ID 2003-01*. Any additional monitoring as determined by the ERCB
Case 2		Depth in accordance with *Directive 008*	Surface casing • cemented in accordance with *Directive 009*. Next casing string • cement top in accordance with *Directive 009*.			• Daily monitoring of annular and tubing pressures • Conduct and report annual packer isolation test in accordance with *ID 2003-01*. Any additional monitoring as determined by the ERCB

Class	Description	Wellbore design		Wellbore integrity logging		Operational monitoring and reporting
		Surface casing to	Casing and cementing	Hydraulic isolation and cement integrity	Casing integrity	
V						
	Cyclic steam stimulation (CSS)	BGWP No surface casing exemption allowed.	Thermal-grade casing, connections, and cement. Surface casing • cemented in accordance with *Directive 009*. Next casing string • cemented to surface.	Initial full-length cement integrity log. Hydraulic isolation log every five years (or an ERCB-approved alternative monitoring program).	Initial full-length casing inspection log if the well is more than five years old. Multifinger caliper log every five years (or an ERCB-approved alternate monitoring program). Casing inspection log every 10 years.	• A 10-minute casing pressure integrity test at the maximum operating pressure running a full gauge ring after every full cycle. Any alternative casing integrity testing must be approved by the ERCB. • When the wellhead temperature of a shut-in well falls below 60°C and the produced stream H_2S partial pressure is above 3 kPa, the wellbore must be purged with a noncorrosive gas or the injection zone must be isolated with a bridge plug. • Continuous monitoring of the injection rate and wellhead injection pressure (WHIP) with any significant fluctuations reported to the ERCB Any additional monitoring as determined by the ERCB.
	Steam-assisted gravity drainage (SAGD)	Depth in accordance with *Directive 008* No surface casing exemption allowed.	Thermal-grade casing, connections, and cement. Surface casing • cemented in accordance with *Directive 009*. Next casing string • cemented to surface.	Initial full-length cement integrity log. Hydraulic isolation log every five years (or an ERCB-approved alternative monitoring program).	Initial full-length casing inspection log if the well is more than five years old. Casing inspection log every 10 years.	• A 10-minute casing pressure integrity test at the maximum operating pressure every 10 years. Any alternative casing integrity testing must be approved by the ERCB. • Wells that have not been operated for more than 30 days must be purged with a noncorrosive gas, or the injection zone must be isolated with a bridge plug. • Continuous monitoring of injection rate and WHIP with any significant fluctuations reported to the ERCB. Any additional monitoring as determined by the ERCB.
	Steam - Other	As directed by the ERCB.	As directed by the ERCB.	As directed by the ERCB.	As directed by the ERCB.	As directed by the ERCB.

5 Common Requirements for All Well Classes

The characteristics of a fluid determine the class of an injection well. A licensee must adhere to the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements for that class of injection well. A licensee applying to inject multiple fluids into a single wellbore must state that intention in its submission for the injection well and meet the requirements for each type of fluid.

A licensee must ensure that all injection wells maintain wellbore integrity and hydraulic isolation of the injection fluids from other porous zones. Any well that does not meet the requirements of this directive may have its application denied or be subject to additional requirements.

A licensee must meet the following requirements:

1) The tubing and casing are a grade and weight that are appropriate for the design conditions and fluid injected.

2) The packer is set within 15 metres (m) of the true vertical depth of the injection perforations in an interval of casing with good cement, or below the next porous interval above the injection zone, whichever is less. If this is not possible, the licensee must request a variance with the *Directive 051* submission. With the exception of previously approved injection wells, a packer is required for all well classes except for Class V wells.

3) The annulus is filled with corrosion-inhibiting fluid and maintained at a positive pressure.

4) The portion of the casing exposed to injection fluids below the perforations does not exceed 15 m. The portion of the wellbore below the injection interval must be abandoned in accordance with *Directive 020: Well Abandonment.*

5) For Class I-IV wells, an initial packer isolation test, if applicable, is conducted for 10 minutes at the greater of the following pressures:

   a) a stabilized pressure of 7000 kilopascals (kPa) or

   b) the maximum approved injection pressure.

   These requirements take precedence over the testing requirements in *ID 2003-01*; however, the reporting requirements from *ID 2003-01* apply.

6) The well data is retained and submitted in accordance with *Directive 059: Well Drilling and Completion Data Filing Requirements* and the *OGCR*. A licensee must report all casing failures in accordance with *ID 2003-01*.

7) The injection rates and casing and tubing pressure monitoring data are available upon request by the ERCB within five business days.

8) Only fluids that meet the criteria listed in Table 1 for the class of injection well for which it received approval are injected.

9) The ERCB will permit, without application, a cumulative fluid injection volume of 500 cubic metres (m^3) to obtain reliable data to support a specified maximum wellhead injection pressure (MWHIP) and to acquire the *Directive 051* information. Any injection requirements to determine the capacity of a formation to accept fluids must be applied for

as an infectivity test application as listed in the DDS system, irrespective of the fluid volume required.

10) For any injection well approved prior to 1994 that has been inactive for five years or more, the licensee must reapply for *Directive 051* approval.

11) *Directive 051* submissions must include all supporting logs. All logs must be submitted to the ERCB in accordance with Section 11.140(1) of the *OGCR* to the ERCB ICD – Data Compliance Services (WellLogInquiries@ercb.ca).

Requirements specific to a given class of injection well, such as timing and frequency of logs, are outlined in Sections 6 to 11.

For the ERCB's casing and cementing requirements, refer to *Directive 008: Surface Casing Depth Requirements*, *Directive 009: Casing Cementing Minimum Requirements*, and *Directive 010: Minimum Casing Design Requirements*.

5.1 Wellbore Integrity Logs

1) A licensee must submit
   a) cement integrity logs,
   b) hydraulic isolation logs,
   c) casing inspection logs, and
   d) a detailed written analysis including geologic formation tops to support the log interpretation.

2) Initial cement integrity, hydraulic isolation, and casing inspection logs must have been run within one year of the registered date of the *Directive 051* application.

   Refer to Appendix 6 for ERCB logging guidelines.

5.1.1 Cement Integrity Logs

1) A cement integrity log must
   a) demonstrate that hydraulic isolation exists between all porous zones,
   b) provide a radial view of cement quality,
   c) identify lightweight cement quality,
   d) be run the full length of vertical injection wells,
   e) be run from the top of the injection zone to the surface for horizontal wells, and
   f) include a zero pressure pass (a pressure pass is optional).

2) A full interpretation of the log on a joint-by-joint basis must be submitted.

5.1.2 Hydraulic Isolation Logs

1) A licensee must submit a hydraulic isolation log that represents the current state of the wellbore as part of the *Directive 051* application.

2) A licensee must provide the volume of fluid used during the hydraulic isolation test.

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5.1.3 Casing Inspection Logs

1) A licensee must run a casing inspection log from which the absolute value of the remaining wall thickness can be determined and submit a full interpretation of the log on a joint-by-joint basis that identifies

   a) anomalies, holes, pits, perforations, metal loss, wall thickness and

   b) internal and external corrosion.

2) A licensee must verify that the remaining pipe-burst rating is equal to or greater than 1.3 times the calculated burst design load using the following equations:

   Remaining pipe burst rating = $P_{yd} = (2Y_pT_d)/D$

   Calculated burst design load = $(P_{max} + (H_d - E_d))$

   where

   P_{yd} = minimum internal yield pressure of casing at the depth of the subject casing joint (kPa)

   Y_p = specified minimum yield strength of casing (kPa)

   T_d = remaining wall thickness at the depth of the subject casing joint (millimetres [mm])

   D = nominal outside diameter (mm)

   P_{max} = maximum allowable wellhead injection pressure (kPa)

   H_d = internal hydrostatic head at the depth of the subject casing joint (kPa)

   E_d = external hydrostatic head at the depth of the subject casing joint (kPa)

3) If the remaining pipe-burst rating is less than 1.3 times the calculated burst design load, a licensee must take the well out of service until appropriate repairs are complete. ERCB approval is required for the repairs.

4) A licensee must assess both internal and external corrosion to determine remaining casing life. Additional operational testing and logging may be required if the corrosion rate is greater than 4 per cent wall loss per year.

5) A licensee must submit a casing inspection log that represents the current state of the wellbore as part of the application.

6 Class Ia and Ib Wells—Nonoilfield and Oilfield Waste

6.1 Wellbore Design (Casing and Cementing)

1) The wellbore casing must be designed in accordance with *Directive 010*.

2) Surface casing must be set to the BGWP and cemented in accordance with *Directive 009*.

3) The next casing string must be cemented to surface.

4) If additional casing strings are used, the combined strings must be cemented to isolate all formations or zones from the base of the well to the surface.

5) Any remedial operations conducted to meet *Directive 051* requirements must be submitted as part of the *Directive 051* submission.

6.2 Wellbore Integrity Logs

1) An initial full-length casing inspection log must be run on the production casing string.

2) An initial cement integrity log and one of the following hydraulic isolation logs must be run to demonstrate hydraulic isolation:

   a) a temperature log,

   b) an oxygen activation log, or

   c) a radioactive tracer log.

3) A hydraulic isolation log must be run every five years from the date of the *Directive 051* approval.

4) A casing inspection log must be run every 10 years from the date of the *Directive 051* approval.

6.3 Operational Monitoring and Reporting

1) Annular and tubing pressures must be continuously monitored and recorded.

2) A packer isolation test must be conducted annually.

   a) This test must be run for 10 minutes at the greater of the following pressures:

      i) 7000 kPa at surface or

      ii) 1.3 times the approved maximum wellhead injection pressure.

   b) The results must be reported in accordance with *ID 2003-01*.

   As set out in *ID 2003-01*, the ERCB will accept a maximum pressure decline of 3 per cent over a 10-minute interval as a successful packer isolation test.

3) A quality assurance / quality control (QA/QC) program must be in place to demonstrate that the fluids received for injection meet the criteria set out in Table 1 for Class Ib wells.

   a) The QA/QC program must include representative sampling and testing of received fluids and retention of fluid shipment information (e.g., truck tickets, Alberta Waste forms, manifests, characterization, and classification information).

   b) QA/QC data and records must be retained for a minimum of five years and made available to the ERCB upon request.

   Surface facilities for Class Ia waste disposal wells, which are located on nonoilfield sites (e.g., petrochemical sites), fall under the jurisdiction of ESRD. Associated reporting and monitoring of fluids received at the surface facility are subject to ESRD requirements.

   Refer to the Waste Management Table in Appendix 7 of *Directive 058* for a list of common oilfield wastes, including related codes, characterization, classification, and management information; refer to *Directive 047* for updated waste codes.

7 Class II Wells—Produced or Saline Water

7.1 Wellbore Design (Casing and Cementing)

Class II injection wells can be classified as either Case 1 or Case 2, depending on whether the next casing string after the surface casing is cemented to surface or cemented in accordance with *Directive 009*. Case 1 involves situations where BGWP is covered by cemented casing. Case 2 involves situations where the BGWP is not covered by cemented casing, for which reason the ERCB requires daily monitoring of the annular and tubing pressures.

1) All new wells drilled for Class II injection must meet the requirements in *Directive 010*. Conversion of existing wells to injection operations where this criterion is not met may be denied or subject to additional wellbore integrity logging, operational monitoring, and reporting requirements.

2) The surface casing must be set in accordance with the requirements of *Directive 008*.

3) Any remedial operations conducted to meet *Directive 051* requirements must be submitted as part of the *Directive 051* submission.

7.2 Wellbore Integrity Logs

1) An initial full-length casing inspection log must be run for any injection well that is more than five years old.

2) An initial cement integrity log, and one of the following hydraulic isolation logs, must be run to demonstrate hydraulic isolation:

   a) a temperature log,

   b) an oxygen activation log, or

   c) a radioactive tracer log.

Additional hydraulic isolation logs may be required over the life of the injection well.

7.3 Operational Monitoring and Reporting

1) Annular and tubing pressures must be monitored and recorded

   a) monthly for Case 1 and

   b) daily for Case 2.

2) A packer isolation test must be conducted annually in accordance with *ID 2003-01* for both Case 1 and Case 2.

3) A QA/QC program must be in place to demonstrate that the fluids received for injection meet the criteria set out in Table 1.

   a) The QA/QC program must include representative sampling and testing of received fluids and retention of fluid shipment information (e.g., truck tickets, or other documentation describing the type and source of fluid).

   b) QA/QC data and records must be retained for a minimum of five years and made available to the ERCB upon request.

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8 Class IIIa Wells—Acid Gas

8.1 Wellbore Design (Casing and Cementing)

1) The wellbore casing must be designed in accordance with *Directive 010*.

2) Surface casing must be set to the BGWP and cemented in accordance with *Directive 009*.

3) The next casing string must be cemented to surface.

4) If additional casing strings are used, the combined strings must be cemented to isolate all formations or zones from the base of the well to the surface.

5) Any remedial operations conducted to meet *Directive 051* requirements must be submitted as part of the *Directive 051* submission.

6) Acid-resistant cement must be used from total depth to above the injection zone. Using lightweight cement or cement with additives such as gypsum or bentonite is unacceptable over the injection zone.

8.2 Wellbore Integrity Logs

1) An initial full-length casing inspection log must be run on the production casing string.

2) An initial cement integrity log and one of the following hydraulic isolation logs must be run to demonstrate hydraulic isolation:

   a) a radioactive tracer log,

   b) a cased hole neutron log that is capable of detecting gas movement,

   c) an oxygen activation log, or

   d) an ERCB-approved alternate log capable of detecting gas movement.

3) A hydraulic isolation log must be run every five years from the date of the *Directive 051* approval.

4) A casing inspection log must be run every 10 years from the date of the *Directive 051* approval.

5) A function test must be conducted semiannually on the subsurface safety valve if one is used.

8.3 Operational Monitoring and Reporting

1) Annular and tubing pressures must be continuously monitored and recorded.

2) A packer isolation test must be conducted annually.

   a) This test must be run for 10 minutes at the greater of the following pressures:

      i) 7000 kPa at surface or

      ii) 1.3 times the approved maximum wellhead injection pressure.

   b) The results must be reported in accordance with *ID 2003-01*.

   As set out in *ID 2003-01*, the ERCB will accept a maximum pressure decline of 3 percent over a 10-minute interval as a successful packer isolation test.

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9 Class IIIb Wells—Hydrocarbons or Other Gases

9.1 Wellbore Design (Casing and Cementing)

Class IIIb injection wells can be classified as either Case 1 or Case 2, depending on whether the next casing string after the surface casing is cemented to surface or cemented in accordance with *Directive 009*. Case 1 involves situations where BGWP is covered by cemented casing. Case 2 involves situations where the BGWP is not covered by cemented casing, for which reason the ERCB requires daily monitoring of the annular and tubing pressures.

1) All new wells drilled for Class IIIb injection must meet the requirements in *Directive 010*. Conversion of existing wells to injection operation where this criterion is not met may be denied or subject to additional wellbore integrity logging, operational monitoring, and reporting requirements.

2) The surface casing must be set in accordance with the requirements of *Directive 008*.

3) Any remedial operations conducted to meet *Directive 051* requirements must be submitted as part of the *Directive 051* submission.

9.2 Wellbore Integrity Logs

1) An initial full-length casing inspection log must be run for any injection well that is more than five years old.

2) An initial cement integrity log and one of the following hydraulic isolation logs must be run to demonstrate hydraulic isolation:

   a) a radioactive tracer log,

   b) a cased hole neutron log that is capable of detecting gas movement, or

   c) an ERCB-approved alternative log capable of detecting gas movement.

Additional hydraulic isolation logs may be required over the life of the injection well.

9.3 Operational Monitoring and Reporting

1) Annular and tubing pressures must be monitored and recorded

   a) monthly for Case 1 and

   b) daily for Case 2.

2) A packer isolation test must be conducted annually in accordance with *ID 2003-01* for both Case 1 and Case 2.

10 Class IV Wells—Nonsaline Water

10.1 Wellbore Design (Casing and Cementing)

Class IV injection wells can be classified as either Case 1 or Case 2, depending on whether the next casing string after the surface casing is cemented to surface or cemented in accordance with *Directive 009*. Case 1 involves situations where BGWP is covered by cemented casing. Case 2 involves situations where the BGWP is not covered by cemented casing, for which reason the ERCB requires daily monitoring of the annular and tubing pressures.

1) All new wells drilled for Class IV injection must meet the requirements in *Directive 010*. Conversion of existing wells to injection operation where this criterion is not met may be denied or subject to additional wellbore integrity logging, operational monitoring, and reporting requirements.

2) The surface casing must be set in accordance with the requirements of *Directive 008*.

3) Any remedial operations conducted to meet *Directive 051* requirements must be submitted as part of the *Directive 051* submission.

10.2 Wellbore Integrity Logs

1) An initial full-length casing inspection log must be run for any injection well that is more than five years old.

2) An initial cement integrity log and one of the following hydraulic isolation logs must be run to demonstrate hydraulic isolation:

   a) a temperature log,

   b) an oxygen activation log, or

   c) a radioactive tracer log.

Additional hydraulic isolation logs may be required over the life of the injection well.

10.3 Operational Monitoring and Reporting

1) Annular and tubing pressures must be monitored and recorded

   a) monthly for Case 1 and

   b) daily for Case 2.

2) A packer isolation test must be conducted annually in accordance with *ID 2003-01* for both Case 1 and Case 2.

11 Class V Wells—Steam

Most Class V injection wells are operated using CSS or SAGD. However, other steam injection technologies are being developed. The wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements for these wells (referred to as Other Class V injection wells) will be determined by the ERCB on a case-by-case basis.

All wells in a drainage pattern must be approved under *Directive 051* before beginning steam injection.

11.1 Wellbore Design (Casing and Cementing)

1) Thermal-grade casing, connections, and cement must be used.

2) The surface casing for CSS wells must be set to the BGWP. Surface casing exemptions do not apply to CSS wells.

3) The surface casing for SAGD wells must be set in accordance with *Directive 008*. Surface casing exemptions do not apply to SAGD wells.

4) The cementing program for all casing strings must result in hydraulic isolation between porous zones and demonstrate that the wellbore has good cement to surface on both the surface casing and the next casing string.

5) All remedial cementing and washover operations on new injection wells must be approved by the ERCB. Any remedial operations conducted must be disclosed in the *Directive 051* application.

11.2 Wellbore Integrity Logs

11.2.1 Common Wellbore Integrity Logs

1) An initial casing inspection log must be run for any injection well that is more than five years old
   a) from the top of the injection zone to surface for directionally drilled or horizontal wells or
   b) full length for vertical wells.

2) A casing inspection log must be run every 10 years from the date of *Directive 051* approval.

3) An initial cement integrity log must be run
   a) from the top of the injection zone to surface for directionally drilled or horizontal wells or
   b) full length for vertical wells.

Initial hydraulic isolation logs are not required.

11.2.2 Additional Cyclic Steam Stimulation Wellbore Integrity Logs

1) A hydraulic isolation log and multifinger caliper log must be run every five years from the date of the *Directive 051* approval.

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Any alternative monitoring plan in lieu of hydraulic isolation and multifinger caliper logging must be approved by the ERCB before beginning steam injection. All monitoring equipment must be installed and operational before steam is injected into a drainage pattern. Monitoring may include a combination of passive seismic, thermal fibre or thermal couples, and aquifer monitoring.

11.2.3 Additional Steam-Assisted Gravity Drainage Wellbore Integrity Logs

1) A hydraulic isolation log must be run every five years from the date of the *Directive 051* approval.

   Any alternative monitoring plan in lieu of hydraulic isolation logging must be approved by the ERCB before beginning steam injection. All monitoring equipment must be installed and operational before steam is injected into a drainage pattern. Monitoring may include a combination of passive seismic, thermal fibre or thermal couples, and aquifer monitoring.

11.3 Operational Monitoring and Reporting

11.3.1 Cyclic Steam Stimulation

1) A casing pressure integrity test must be conducted for 10 minutes at the maximum operating pressure, and a full gauge ring must be run after every full cycle. Any alternative casing integrity testing must be approved by the ERCB.

2) When the wellhead temperature of a shut-in well falls below 60°C and the produced stream H_2S partial pressure is above 3 kPa, a licensee must
   a) purge the well with a noncorrosive gas or
   b) isolate the injection zone from the wellbore by setting a bridge plug.

3) The injection rate and WHIP must be continuously monitored and any significant fluctuations reported to the ERCB.

Additional monitoring may be required over the life of the injection well.

11.3.2 Steam-Assisted Gravity Drainage

1) A casing pressure integrity test must be conducted for 10 minutes at the maximum operating pressure every 10 years from the date of *Directive 051* approval. Any alternative casing integrity testing must be approved by the ERCB.

2) When a well has not been operated for more than 30 days, the licensee must
   a) purge the well with a noncorrosive gas or
   b) isolate the injection zone from the wellbore by setting a bridge plug.

3) The injection rate and WHIP must be continuously monitored and any significant fluctuations reported to the ERCB.

Additional monitoring may be required over the life of the injection well.

12 In Situ Coal Conversion and In Situ Combustion

1) In situ coal conversion and in situ combustion injection wells must

a) have thermal-grade casing, connections, and cement and

b) meet the requirements in Sections 5 through 11 associated with the applied-for class or classes.

13 Downhole Separation and Injection

1) A licensee of a producing well that uses an in-well oil-water, gas-oil, or gas-water separator that allows produced water to be reinjected downhole without surface separation and treatment processes must apply to the ERCB for approval to use the well as a Class II injection well.

The casing integrity between the production and disposal zones cannot be easily assessed with this type of technology (e.g., a packer isolation test is not possible). Therefore, downhole separation and injection is generally limited to situations where disposal is below the hydrocarbon and water interface in a single zone or the next lower water-bearing zone.

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Appendix 1 *Directive 051* Form

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ERCB Energy Resources Conservation Board	**Directive 051 Form**

Boxes with a **bold YES** beside them require an answer of **YES** to proceed.

ERCB USE ONLY
IAR Number: _____

PART I: General Information

Well class: Ia ☐ Ib ☐ II ☐ IIIa ☐ IIIb ☐ IV ☐ V ☐ Company name: _____

BA code: _____

Well name: _____ Well UWI: | LE | / | LSD | SEC | TWP | RGE | W | Meridian | / | ES |

Well licence number: _____ Rig release date: _____

Scheme approval number: _____ MWHIP: _____ kPa

Field name: _____ Pool name: _____

Injection interval: _____ mKB to _____ mKB Injection formation: Top: _____ mKB _____ mTVD

_____ mTVD to _____ mTVD Bottom: _____ mKB _____ mTVD

Is a list of the formation tops attached to the application? ☐ **YES**

Daily injection volume: _____ m^3/d

Source of fluids: _____

Is the Well Class correct for the fluid type injected? (Refer to Table 1)? ☐ **YES**

Does the fluid being injected contain H_2S? ☐ YES ☐ NO

PART II: Groundwater Protection

Base of groundwater protection: _____ mASL _____ mKB _____ mTVD

PART III: Well Details

Surface casing depth: _____ mKB _____ mTVD Intermediate casing depth: _____ mKB _____ mTVD

Production casing depth: _____ mKB _____ mTVD

Liner: Top: _____ mKB _____ mTVD Bottom: _____ mKB _____ mTVD

Packer depth: _____ mKB _____ mTVD Total depth: _____ mKB _____ mTVD

Is a well schematic attached? ☐ **YES**

Is a completions report attached? ☐ **YES**

(continued)

PART IV: Cementing Requirements

Cement type: _____

Is the base of groundwater protection covered with cemented casing? ☐ YES ☐ NO

Is the surface casing cemented to surface? ☐ **YES**

Is the production casing cemented to surface? ☐ YES ☐ NO

If no, what is the cemented top of the production casing? _____ mKB _____ mTVD

Was a cement integrity log run? ☐ **YES** Date log was run: _____

Is a copy of the log and the interpretation attached? ☐ **YES**

Is this a radial bond log? ☐ **YES**

Cement integrity log run depth: Top: _____ mKB _____ mTVD Bottom: _____ mKB _____ mTVD

PART V: Hydraulic Isolation

Was a hydraulic isolation log run? ☐ YES ☐ NO Date log was run: _____

If yes, is a copy of the log and the interpretation attached? ☐ YES

If yes, is a discussion on hydraulic isolation of both the injection zone and nonsaline groundwater attached? ☐ YES

Total volume of fluid used for the hydraulic isolation test: _____ m^3

Depth of the hydraulic isolation log: Top: _____ mKB _____ mTVD Bottom: _____ mKB _____ mTVD

PART VI: Casing Integrity

Was a casing inspection log run? ☐ YES ☐ NO Date log was run: _____

If yes, is a copy of the log and the joint-by-joint interpretation attached? ☐ YES

If yes, does the casing inspection log determine the absolute value of the remaining wall thickness? ☐ YES

Has there been a casing failure? ☐ YES ☐ NO

If yes, are details on how it was repaired attached? ☐ YES

Has a pressure test on the casing and packer been completed? (Refer to Section 5) ☐ YES ☐ NO

If yes, casing pressure tested to _____kPa for _____minutes on _____date.

If yes, packer pressure tested to _____kPa for _____minutes on _____date.

Type of corrosion inhibitor fluid used in the tubing / casing annulus? _____

Is there surface casing vent flow? ☐ YES ☐ NO

Appendix 2 How to Complete the *Directive 051* Form

Part I: General Information

Well class	Check the class(es) of well being applied for. Any licensee applying to inject multiple types of fluids into a single wellbore must submit one application that addresses the requirements of each class of well.
Company name	Enter the company name.
BA code	Enter the BA code obtained from the Petroleum Registry of Alberta.
Well name	Enter the name of the well as it currently appears on the licence.
Well UWI	Enter the full unique well identifier (UWI), including the location exception code (LE) and event sequence (ES).
Well licence number	Enter the well licence number assigned by the ERCB.
Rig release date	Enter the date the rig was released.
Scheme approval number	Enter the scheme approval number from the *Directive 065* or *Directive 023* application, if available.
MWHIP	Enter the approved or proposed maximum wellhead injection pressure (MWHIP) in kPa, if available.
Field name	Enter the field name.
Pool name	Enter the name of the pool associated with the well.
Injection interval	Enter the depth of the injection interval. Include measurements in both metres below kelly bushing (mKB) and metres true vertical depth (mTVD).
Injection formation	Enter the depth of the top and bottom of the formation being injected into. Include measurements in both mKB and mTVD.
Is a list of formation tops attached to the application?	A list of the formation tops must be attached to the application. Select YES to confirm that the list is attached.
Daily injection volume	Enter the volume of fluids injected daily in cubic metres per day (m^3/day).
Source of fluids	Enter the source of fluids being injected.
Is the Well Class correct for the fluid type injected?	Select YES to confirm that this is true. Refer to Table 1.
Does the injection fluid contain H_2S?	Select YES if the fluid being injected contains H_2S. Select NO if the fluid being injected does not contain H_2S.

Part II: Groundwater Protection

Base of groundwater protection	Enter the depth of the BGWP in metres above sea level (mASL), mKB, and mTVD.

Part III: Well Details

Surface casing depth	Enter the depth of the surface casing in mKB and mTVD.
Intermediate casing depth	Enter the depth of the intermediate casing in mKB and mTVD.
Production casing depth	Enter the depth of the production casing in mKB and mTVD.
Liner	Enter the depth of the liner top and bottom in mKB and mTVD.
Packer depth	Enter the depth of the packer in mKB and mTVD.
Total depth	Enter the total depth (TD) in mKB and mTVD.
Is a well schematic attached?	A wellbore schematic must be attached to the application. Select YES to confirm that it is attached. All well schematics must be in the format shown in Appendix 3 and contain the following information, if applicable: a) kelly bushing (KB) and ground elevation; b) surface casing specifications, depth, and confirmation that surface casing is cemented to surface; c) intermediate and production string specifications, depth, and cement top; d) liner specifications and setting depth, if applicable; e) tubing specifications and depth; f) depth of subsurface safety valves; g) packer type and setting depth (measured at the centre element); h) all perforations and status; i) top and bottom of injection formation; j) abandoned or suspended zones below or above the injection zone; and k) any other information relevant to well operations.
Is a completions report attached?	A completions report must be attached to the application. Select YES to confirm that it is attached.

Part IV: Cementing Requirements

Cement type	Enter the type of cement used.
Is the base of groundwater protection covered with cemented casing?	Select YES if the BGWP has been covered with cemented casing. Select NO if the BGWP has not been covered with cemented casing.

Is the surface casing cemented to surface?	Surface casing must be cemented to surface. Select YES to indicate that this is true.
Is the production casing cemented to surface?	Select YES if the production casing was cemented to surface. Select NO if the production casing was not cemented to surface.
If no, what is the cemented top of the production casing?	Enter the cemented top of the production casing in mKB and mTVD.
Was a cement integrity log run?	A full-length cement integrity log must be run from the top of the injection formation to surface. Select YES to confirm that one has been run.
Date log was run	Enter the date the cement integrity log was run.
Is a copy of the log and the interpretation attached?	A copy of the cement integrity log with an interpretation must be submitted with the application. Select YES to confirm that both the log and interpretation are attached.
Is this a radial bond log?	Cement integrity logs must be capable of providing a radial view of cement quality. Select YES to confirm that the cement integrity log attached provides a radial view of the cement quality.
Cement integrity log run depth	Enter the depth of the top and bottom of the cement integrity log in mKB and mTVD.

Part V: Hydraulic Isolation

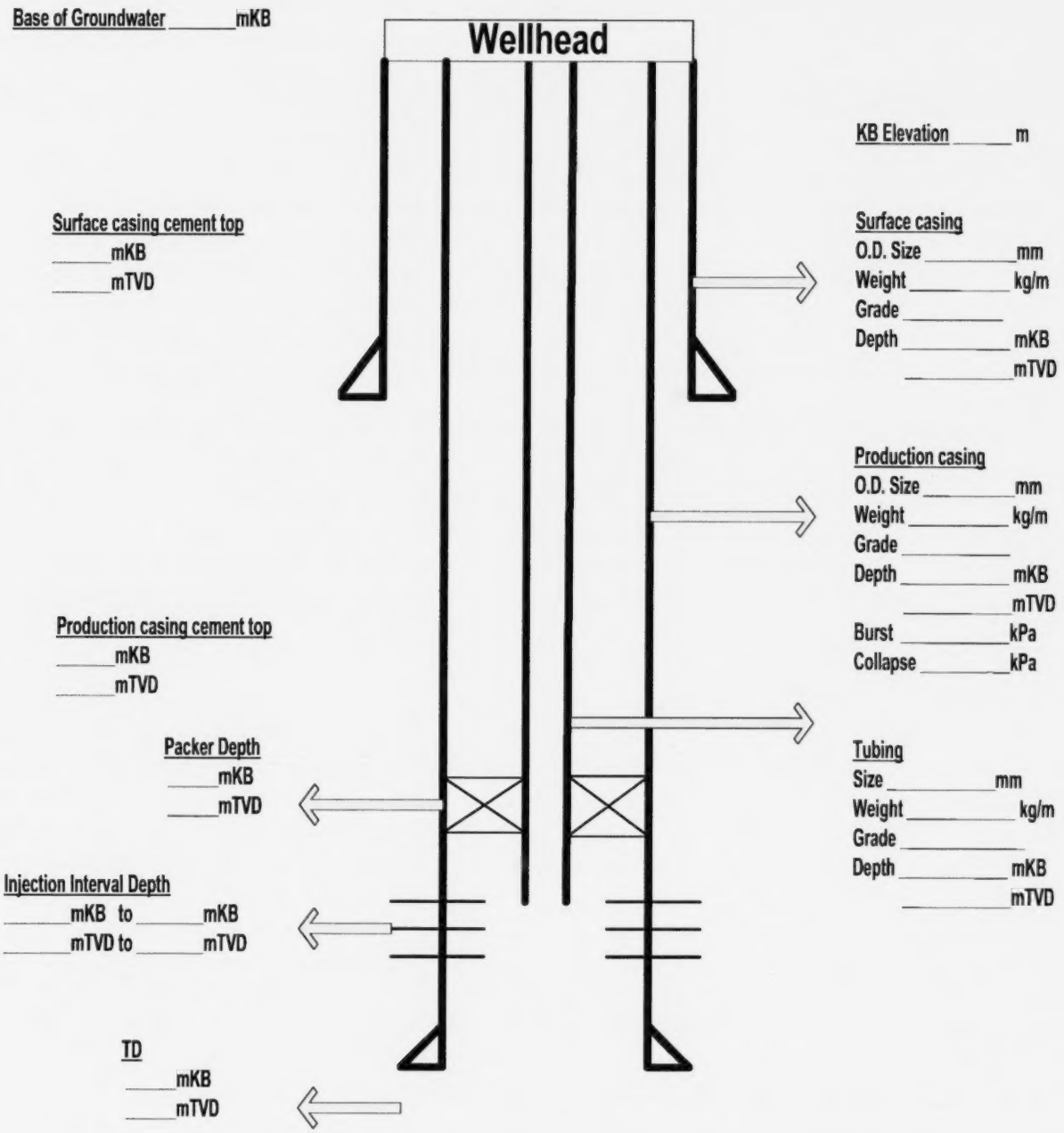
Was a hydraulic isolation log run?	Hydraulic isolation logs must be run. Select YES to confirm that one was run. Select NO if an initial hydraulic isolation log is not required.
Date log was run	Enter the date the hydraulic isolation log was run.
If yes, is a copy of the log and the interpretation attached?	A copy of the hydraulic isolation log with an interpretation must be attached. Select YES to confirm that both the hydraulic isolation log and interpretation are attached.
If yes, is a discussion on hydraulic isolation of both the injection zone and nonsaline groundwater attached?	The hydraulic isolation of both the injection zone and nonsaline groundwater must be discussed in detail and attached to the application. Select YES to confirm that it is attached.
Total volume of fluid used	Enter the total volume of fluid injected for the hydraulic isolation test in

for the hydraulic isolation test	m^3.
Depth of the hydraulic isolation log run	Enter the top and bottom depth of the hydraulic isolation log run in mKB and mTVD.

Part VI: Casing Integrity

Was a casing inspection log run?	Select YES if a full-length casing inspection log has been run. Select NO if a full-length casing inspection log has not been run.
Date log was run	Enter the date the casing inspection log was run.
If yes, is a copy of the log and a joint-by-joint interpretation attached?	A copy of the log with a joint-by-joint interpretation must be attached (refer to Section 5.1.3). Select YES to confirm that both the log and interpretation are attached.
If yes, does the casing inspection log determine the absolute value of the remaining wall thickness?	The absolute value of the remaining wall thickness must be able to be determined from the casing inspection log. Select YES to confirm that this is true.
Has there been a casing failure?	Select YES if a casing failure with the production casing or liner has occurred. Select NO if a casing failure has not occurred.
If yes, are details on how it was repaired attached?	If a casing or liner failure occurred, an explanation of how the casing was repaired must be attached. Select YES to confirm that these details are attached.
Has a pressure test on the casing and packer been completed?	A pressure test on the casing and packer must be completed in accordance with Section 5. Select YES if this test has been completed. If YES, enter the pressure the casing and packer were tested to in kPa, the duration of the test in minutes, and the date of the test. Select NO if this test has not been completed.
Type of corrosion inhibitor fluid used in the tubing/casing annulus	Enter the type of fluid used as a corrosion inhibitor fluid in the tubing/casing annulus.
Is there surface casing vent flow?	Select YES if the well has surface casing vent flow. Select NO if the well has no surface casing vent flow.

Appendix 3 Sample Injection Wellbore Completion Schematic



For additional direction refer to Appendix 2: "How to Complete the *Directive 051* Form."

Appendix 4 References

Acts and Regulations

Coal Conservation Act

Oil and Gas Conservation Act

Oil and Gas Conservation Regulations

Oil Sands Conservation Act

Oil Sands Conservation Regulation

Alberta Environmental Protection and Enhancement Act (*ESRD*)

Waste Control Regulation (*ESRD*)

Water Act (*ESRD*)

ERCB Directives, Interim Directives, and Bulletins

Bulletin 2010-17: Clarification to the "Memorandum of Understanding Between the Alberta Energy and Utilities Board and Alberta Environment Regarding Subsurface Waste Disposal Applications" (Bulletin 2007-06)

Directive 007: Volumetric and Infrastructure Requirements

Directive 008: Surface Casing Depth Requirements

Directive 009: Casing Cementing Minimum Requirements

Directive 010: Minimum Casing Design Requirements

Directive 019: Compliance Assurance

Directive 020: Well Abandonment

Directive 023: Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project

Directive 036: Drilling Blowout Prevention Requirements and Procedures

Directive 043: Well Logging Requirements – Surface Casing Interval

Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities

Directive 050: Drilling Waste Management

Directive 055: Storage Requirements for the Upstream Petroleum Industry

Directive 056: Energy Development Applications and Schedules

Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry

Directive 059: Well Drilling and Completion Data Filing Requirements

Directive 065: Resources Applications for Oil and Gas Reservoirs

ID 2000-03: Harmonization of Waste Management

ID 2003-01: 1) Isolation Packer Testing, Reporting, and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements

Canadian Standards Association

CSA Z341: Storage of Hydrocarbons in Underground Formations

Appendix 5 Definitions

Acid gas	Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), totally reduced sulphur compounds, and/or carbon dioxide (CO_2).
Cement integrity log	A tool that will provide a radial view of cement behind casing and is capable of detecting channeling.
Class Ia injection wells	Wells used for the injection of nonoilfield wastes. The operation of associated surface facilities is regulated by Alberta Environment and Sustainable Resources Development.
Class Ib injection wells	Wells used for the injection of oilfield wastes and a mixture of oilfield and nonoilfield wastes. The operation of the associated surface facilities are regulated by the ERCB.
Class II injection wells	Wells used for the injection of produced or saline water.
Class IIIa injection wells	Wells used for the injection of acid gas. This includes • injection of acid gas into a reservoir zone for the purpose of enhanced recovery or pressure maintenance or • the injection of carbon dioxide from industrial sources into a reservoir zone or cavern for the purpose of storage, sequestration, or disposal. Acid gas may include traces of gas impurities.
Class IIIb injection wells	Wells used for the injection of hydrocarbons or other gases.
Class IV injection wells	Wells used for the injection of nonsaline fluid.
Class V injection wells	Wells used for injection of steam. This includes production wells where steam injection occurs even for a limited period.
Continuous monitoring	An automated feedback mechanism to collect real time data on well tubing and annulus pressures.
Cyclic Steam Stimulation (CSS) cycle	The sequence of operations from the commencement of steam injection to the end of bitumen production for a well. There are multiple cycles of varying lengths in the life of a CSS well.
Fluid/waste classification	The characteristics or properties of a waste that classify it as dangerous or hazardous under *Directive 058* or the *Waste Control Regulation*.
Hydraulic isolation log	A log that detects the flow of injected fluids behind the casing string.
In situ Coal Conversion	The thermal or chemical conversion of coal into synthetic coal gas or synthetic coal liquid, in an underground coal seam, using an industrial process.
In Situ Combustion	Also know as fire flooding. This is a thermal recovery method in which

	combustion is created in the reservoir by injecting a gas containing oxygen.
Nonoilfield Waste	Nonoilfield waste means any waste generated in Alberta that is not an oilfield waste and any waste imported into Alberta.
Oilfield Waste	An unwanted substance or mixture of substances that results from the construction, operation, abandonment or reclamation of a facility, well site or pipeline, but does not include an unwanted substance or mixture of substances from such a source that is received for storage, treatment, disposal, or recycling at a facility that is regulated by Department of Environment (ESRD).
Oxygen activation log	A hydraulic isolation log that employs pulsed neutron techniques to activate oxygen nuclei, creating a radioactive nitrogen isotope with a very short half-life which decays back to oxygen.
Packer isolation test	A pressure test of the tubing/casing annulus designed to evaluate the integrity of the casing, tubing, and packer.
Produced water	Water that is present in a hydrocarbon reservoir and is produced to surface with the crude oil, bitumen, or natural gas. The composition of the separated produced water depends on the formation from which it was produced and can contain residual liquid or gaseous hydrocarbons, dissolved or suspended solids, produced solids such as silt or sand, and injected fluids and additives that are used in normal oil, bitumen, and gas production operations. Fluids produced back to surface immediately after a well has undergone a workover/simulation will contain a higher level of additives and, therefore, are considered well workover fluids—a type of oilfield waste—and not produced water.
Radioactive tracer log	A hydraulic isolation log that injects soluble radioactive material with a downhole injector at or near the maximum allowable injection pressure. Refer to the Canadian Nuclear Safety Commission (CNSC) for requirements on use and management of radioactive materials.
Waste minimization	The reduction of a waste stream to be disposed by assessment of the following parameters: source reduction, potential for reuse, potential to recycle, or potential to recover useful components. This assessment should include a full-cycle analysis of environmental benefits, economic and technically feasible options.

Appendix 6 Logging Guidelines

The following are general guidelines that should be considered when running a hydraulic isolation, casing, or cement integrity log. Certain aspects of these guidelines may not be appropriate in all situations. Regardless, logging company representatives should always be made aware of why logging is being conducted to ensure that the configuration of programs and tools is appropriate for the specific well situation.

Hydraulic Isolation Logs

For all logs requiring injection (i.e., temperature, radioactive tracer, and oxygen activation), the following general design considerations apply:

- The well should be capable of accepting a stable injection rate, with sufficient fluid made available to conduct the entire logging program.
- Logging should be conducted with the well under normal injection conditions, preferably at or near the approved or requested maximum wellhead injection pressure.
- Wireline pressure control equipment that is capable of maintaining a casing pressure at least equal to the maximum injection pressure without significant pressure bleed-off while logging should be installed.
- The hydraulic isolation log must be run from the top of the injection interval to at least 200 m above the top of the zone of interest.

1) Temperature Logs

The temperature of the injected fluid should be adjusted to provide for a differential of at least 5°C at the injection zone. All temperature logs should be obtained logging down at a limit of 10 m per minute with the speed displayed on the log.

If conducting a temperature log on a horizontal well, an extended reach system may be needed.

Wells with or without prior injection (e.g., new, existing, extended shut-in, and converted wells)

The following procedures should be followed if no significant injection has occurred or the well has been shut in for an extended period where wellbore temperatures would be expected to be near geothermal.

- With the well shut in, run a baseline temperature log (logged down) and a baseline gamma ray log (logged up) from approximately 200 m above the top of the zone of interest to plug back total depth (PBTD).
- Inject a volume of fluid at or near the maximum operating pressure under normal injection conditions.
- With the well shut in, conduct four temperature runs (logged down) at intervals of at least a half hour to help identify storage areas. Be aware of boundary effects when analyzing for reservoir inflow.

The shut-in logs obtained should be presented as a composite overlay on the same axis for comparative purposes. Displays should enhance visual identification of anomalies by compressing the depth scale and expanding the temperature scale.

If running a temperature log on a Class V injection well, it should be run a minimum of 200 m above the injection zone, full length if TD is less than 200 m, or to the top of the horizontal section. Temperature logs should be run at a target downhole temperature in the range of 140°C to 160°C.

2) Radioactive Tracer Logs

Radioactive tracer logs can be effective for detecting near-wellbore flow behind casing. The tracer material should be compatible with the injection fluid to avoid density segregation or dropout of the tracer material. Logging tools should be centralized to avoid tracer ejection against the casing wall. The wellbore should be clear of tubing and packers over the zone of interest wherever practical to avoid any radioactive tracer traps and to enhance interpretation.

The logging program should include the following basic components:

- The radioactive tracer material should be miscible with the fluid/gas being injected.
- With the well shut in, a baseline gamma ray (logged up) should be run from the TD or the PBTD to at least 200 m above the top of the zone of interest.
- With the well under a stable injection rate at or near the maximum injection pressure, a series of stationary tracer injections should be performed commencing above and continuing through the perforated interval until the bottom detector no longer detects the ejected slug. In cases of low injection rates, log-through procedures may be used in which the tracer ejections are not stationary.
- Injection of a slug of tracer above the perforations should be followed by four consecutive logging runs (i.e., storage passes) from the TD or the PBTD to 200 m above the zone of interest until the slug disappears or becomes stationary.
- It is recommended that stationary checks be performed above the packer to verify that the packer is holding (if applicable).

The results of the storage passes should be presented as a composite overlay.

The ERCB does not recommend that radioactive tracer logs be performed on steam injection wells due to increased risks in handling radioactive materials in the vapour phase.

3) Oxygen Activation Logs

The following general procedures should be followed when using oxygen activation logs for evaluating hydraulic isolation.

- With the wells under injection at or near the maximum wellhead injection pressure, take measurements at a minimum of three stations above the injection interval.
- Additional readings should be taken above and below any anomalous readings.

4) Cement Integrity Logs

All cement integrity logs should be run after cement has cured; the timing of the logs is subject to the cement blend and downhole wellbore conditions.

a) General Design Considerations

- The well history should be researched to determine the cement type and anticipated placement, casing sizes and grades, and maximum fluid pressure exerted on the casing since the annular cement has cured.
- The logging tool should be selected and calibrated for the type of cement used.
- The logging tool should be properly centralized in the casing and be appropriately sized for the diameter casing used.

b) Well Preparation

- The casing should be cleared of any internal cement sheathing prior to logging.
- The wellbore fluid should be displaced with a consistent fluid of either fresh water, drilling mud, or dead crude. Mud weights should be kept below 1200 kilograms per cubic metre to avoid attenuation problems.

c) Logging Procedures

- The main logging pass should, where possible, be run with the maximum historical fluid pressure on the casing to avoid microannulus effects.
- If possible, a section of free pipe should be logged as a baseline reference and for transit time / amplitude calibration.

5) Casing inspection logs

a) General Design Considerations

- The history of the well should be researched to determine all casing sizes, weights, and any activities that would influence the magnetic characteristics of the wellbore.

b) Well Preparation

- All tubing and mechanical items should be removed from the well.